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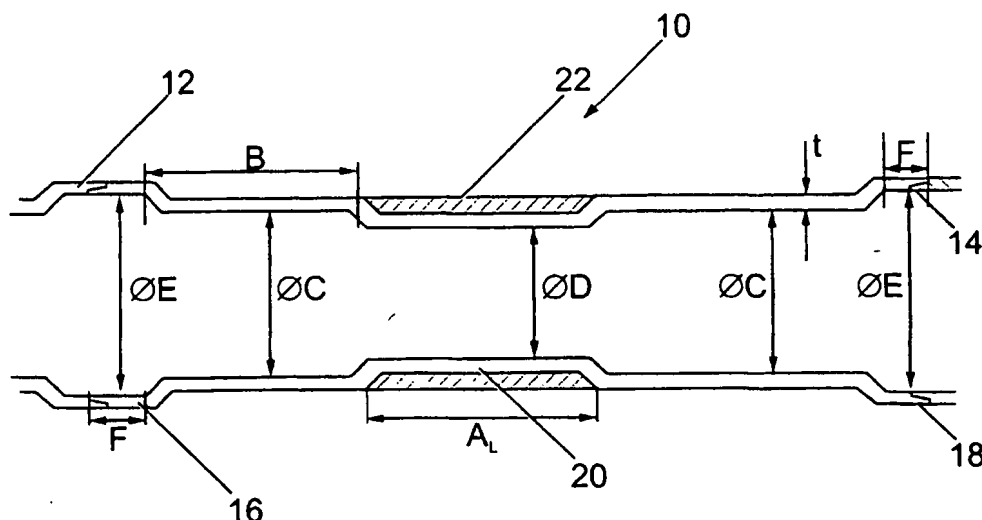
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(54) Title: **EXPANDABLE DOWNHOLE TUBING**



(57) Abstract: The present invention relates to portions of casing that are inserted into a wellbore. The casing portions are provided with a protected portion in which a friction and/or sealing material can be located. In certain embodiments, the protected portion is provided by first and second annular shoulders that are spaced-apart axially along the length of the casing. The friction and/or sealing material is typically located on an outer surface of the casing between the annular shoulders. There is also provided a casing portion that has annular shoulders provided at either end of the casing portion, with means to connect successive casing portions located on these shoulders. The casing portion in this embodiment is provided with a friction and/or sealing material in a recessed portion of the casing portion.

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For two-letter codes and other abbreviations, refer to the "Guidance Notes on Codes and Abbreviations" appearing at the beginning of each regular issue of the PCT Gazette.

EXPANDABLE DOWNHOLE TUBING

1

2

3

4 The present invention relates to apparatus and methods
5 and particularly, but not exclusively, to an expander
6 device and method for expanding an internal diameter of
7 a casing, pipeline, conduit or the like. The present
8 invention also relates to a tubular member such as a
9 casing, pipeline, conduit or the like.

10

11 A borehole is conventionally drilled during the
12 recovery of hydrocarbons from a well, the borehole
13 typically being lined with a casing. Casings are
14 installed to prevent the formation around the borehole
15 from collapsing. In addition, casings prevent unwanted
16 fluids from the surrounding formation from flowing into
17 the borehole, and similarly, prevent fluids from within
18 the borehole escaping into the surrounding formation.

19

20 Boreholes are conventionally drilled and cased in a
21 cascaded manner; that is, casing of the borehole begins

1 at the top of the well with a relatively large outer
2 diameter casing. Subsequent casing of a smaller
3 diameter is passed through the inner diameter of the
4 casing above, and thus the outer diameter of the
5 subsequent casing is limited by the inner diameter of
6 the preceding casing. Thus, the casings are cascaded
7 with the diameters of the successive casings reducing
8 as the depth of the well increases. This successive
9 reduction in diameter results in a casing with a
10 relatively small inside diameter near the bottom of the
11 well that could limit the amount of hydrocarbons that
12 can be recovered. In addition, the relatively large
13 diameter borehole at the top of the well involves
14 increased costs due to the large drill bits required,
15 heavy equipment for handling the larger casing, and
16 increased volumes of drill fluid which are required.
17

18 Each casing is typically cemented into place by filling
19 an annulus created between the casing and the
20 surrounding formation with cement. A thin slurry
21 cement is pumped down into the casing followed by a
22 rubber plug on top of the cement. Thereafter, drilling
23 fluid is pumped down the casing above the cement that
24 is pushed out of the bottom of the casing and into the
25 annulus. Pumping of drilling fluid is stopped when the
26 plug reaches the bottom of the casing and the wellbore
27 must be left, typically for several hours, whilst the
28 cement dries. This operation requires an increase in
29 drill time due to the cement pumping and hardening
30 process, which can substantially increase production
31 costs.
32

1 To overcome the associated problems of cementing
2 casings and the gradual reduction in diameters thereof,
3 it is known to use a more pliable casing that can be
4 radially expanded so that an outer surface of the
5 casing contacts the formation around the borehole. The
6 pliable casing undergoes plastic deformation when
7 expanded, typically by passing an expander device, such
8 as a ceramic or steel cone or the like, through the
9 casing. The expander device is propelled along the
10 casing in a similar manner to a pipeline pig and may be
11 pushed (using fluid pressure for example) or pulled
12 (using drill pipe, rods, coiled tubing, a wireline or
13 the like).

14
15 Additionally, a rubber material or other high friction
16 coating is often applied to selected portions of the
17 outer surface of the unexpanded casing to increase the
18 grip of the expanded casing on the formation
19 surrounding the borehole or previously installed
20 casing. However, when the casing is being run-in, the
21 rubber material on the outer surface is often abraded
22 during the process, particularly if the borehole is
23 highly deviated, thereby destroying the desired
24 objective.

25
26 According to a first aspect of the present invention
27 there is provided a tubular member for a wellbore, the
28 tubular member including coupling means to facilitate
29 coupling of the tubular member into a string, the
30 coupling means being disposed on an annular shoulder
31 provided at at least one end of the tubular member, the
32 tubular member further including at least one recess

1 wherein a friction and/or sealing material is located
2 within the recess.

3

4 Typically, the tubular member is a casing, pipeline,
5 conduit or the like. The tubular member may be of any
6 length, including a pup joint.

7

8 The at least one recess is preferably an annular
9 recess.

10

11 The at least one recess is typically weakened to
12 facilitate plastic deformation of the at least one
13 recess. Heat is typically used to weaken the at least
14 one recess.

15

16 The internal diameter of the at least one recess is
17 typically reduced with respect to the internal diameter
18 of the tubular member adjacent the recess. The
19 internal diameter of the at least one recess is
20 typically reduced by a multiple of a wall thickness of
21 the tubular member. The internal diameter of the at
22 least one recess is preferably reduced by an amount
23 between 0.5 and 5 times the wall thickness, and most
24 preferably by an amount between 0.5 and 2 times the
25 wall thickness. Values outside of these ranges may
26 also be used.

27

28 Preferably, the coupling means is disposed on an
29 annular shoulder provided at each end of the tubular
30 member. The coupling means typically comprises a
31 threaded coupling. A first screw thread is typically
32 provided on the annular shoulder at a first end of the

1 tubular member, and a second screw thread is typically
2 provided on the annular shoulder at a second end of the
3 tubular member. The coupling means typically comprises
4 a pin connection on one end and a box connection on the
5 other end. Thus, a casing string or the like can be
6 created by threadedly coupling successive lengths of
7 tubular member.

8
9 The inner diameter of the annular shoulder is typically
10 enlarged with respect to the inner diameter of the
11 tubular member adjacent the annular shoulder. The
12 inner diameter of the annular shoulder is typically
13 increased by a multiple of a wall thickness of the
14 tubular member. The inner diameter of the annular
15 shoulder is preferably enlarged by an amount between
16 0.5 and 5 times the wall thickness, and most preferably
17 enlarged by an amount between 0.5 and 2 times the wall
18 thickness. Values outside of these ranges may also be
19 used.

20
21 The tubular member is preferably manufactured from a
22 ductile material. Thus, the tubular member is capable
23 of sustaining plastic deformation.

24
25 According to a second aspect of the present invention
26 there is provided an expander device comprising a body
27 provided with a first annular shoulder, and a second
28 annular shoulder spaced apart from the first annular
29 shoulder.

30

1 The expander device is typically used to expand the
2 diameter of a tubular member such as a casing,
3 pipeline, conduit or the like.

4

5 The radial expansion of the second annular shoulder is
6 preferably greater than the radial expansion of the
7 first annular shoulder.

8

9 The expander device is preferably used to expand a
10 tubular member, the tubular member including coupling
11 means to facilitate coupling of the tubular member into
12 a string, the coupling means being disposed on an
13 annular shoulder provided at at least one end of the
14 tubular member, the tubular member further including at
15 least one recess wherein a friction and/or sealing
16 material is located within the recess.

17

18 The second annular shoulder is preferably spaced apart
19 from the first annular shoulder by a distance
20 substantially equal to the distance between an annular
21 shoulder of a preceding tubular member (when coupled
22 together into a string) and the at least one recess of
23 the tubular member. Preferably, the first annular
24 shoulder of the expander device contacts the at least
25 one recess of the tubular member substantially
26 simultaneously with the second annular shoulder of the
27 expander device entering an annular shoulder of the
28 tubular member. The force required to expand the
29 annular shoulder of the tubular member is significantly
30 less than the force required to expand the nominal
31 inner diameter portions of the tubular member. Thus,
32 as the second annular shoulder of the expander device

1 enters the annular shoulder of the tubular member, the
2 force required to expand the nominal inner diameter
3 portions of the tubular member is not required to
4 expand the annular shoulders of the tubular member and
5 the difference in force facilitates an increase in the
6 force which is required to expand the diameter of the
7 at least one recess.

8

9 The expander device is typically manufactured from
10 steel. Alternatively, the expander device may be
11 manufactured from ceramic, or a combination of steel
12 and ceramic. The expander device is optionally
13 flexible.

14

15 The expander device is optionally provided with at
16 least one seal. The seal typically comprises at least
17 one O-ring.

18

19 The expander device is typically propelled through the
20 tubular member, pipeline, conduit or the like using
21 fluid pressure. Alternatively, the device may be
22 pigged along the tubular member or the like using a
23 conventional pig or tractor. The device may also be
24 propelled using a weight (from the string for example),
25 or may be pulled through the tubular member or the like
26 (using drill pipe, rods, coiled tubing, a wireline or
27 the like).

28

29 According to a third aspect of the present invention,
30 there is provided a method of lining a borehole in an
31 underground formation, the method comprising the steps
32 of lowering a tubular member into the borehole, the

1 tubular member including coupling means to facilitate
2 coupling of the tubular member into a string, the
3 coupling means being disposed on an annular shoulder
4 provided at at least one end of the tubular member, the
5 tubular member further including at least one recess
6 wherein a friction and/or sealing material is located
7 within the recess, and applying a radial force to the
8 tubular member using an expander device to induce a
9 radial deformation of the tubular member and/or the
10 underground formation.

11
12 The expander device preferably comprises a body
13 provided with a first annular shoulder, and a second
14 annular shoulder spaced apart from the first annular
15 shoulder.

16
17 The method typically includes the further step of
18 removing the radial force from the tubular member.

19
20 The tubular member is preferably manufactured from a
21 ductile material. Thus, the tubular member is capable
22 of sustaining plastic deformation.

23
24 The at least one recess is preferably an annular
25 recess.

26
27 The at least one recess is typically weakened to
28 facilitate plastic deformation of the at least one
29 recess. Heat is typically used to weaken the at least
30 one recess.

31

1 The friction and/or sealing material is typically
2 located within the at least one recess when the tubular
3 member is unexpanded. The friction and/or sealing
4 material typically becomes proud of the outer surface
5 adjacent the at least one recess of the tubular member
6 when the at least one recess is expanded by the first
7 annular shoulder on the expander device. The friction
8 and/or sealing material typically becomes proud of the
9 outer surface of the tubular member when the at least
10 one recess is expanded by the second annular shoulder
11 on the expander device.

12
13 The internal diameter of the at least one recess is
14 typically reduced with respect to the internal diameter
15 of the tubular member adjacent the recess. The
16 internal diameter of the at least one recess is
17 typically reduced by a multiple of a wall thickness of
18 the tubular member. The internal diameter of the at
19 least one recess is preferably reduced by an amount
20 between 0.5 and 5 times the wall thickness, and most
21 preferably reduced by an amount between 0.5 and 2 times
22 the wall thickness. Values outside of these ranges may
23 also be used.

24
25 Preferably, the coupling means is disposed on an
26 annular shoulder provided at at least one end of the
27 tubular member. The coupling means typically comprises
28 a threaded coupling. A first screw thread is typically
29 provided on the annular shoulder at a first end of the
30 tubular member, and a second screw thread is typically
31 provided on the annular shoulder at a second end of the
32 tubular member. The coupling means typically comprises

1 a pin connection on one end and a box connection on the
2 other end. Thus, a tubular member string can be
3 created by threadedly coupling successive lengths of
4 tubular member.

5
6 The inner diameter of the annular shoulder is typically
7 enlarged with respect to the inner diameter of the
8 tubular member adjacent the annular shoulder. The
9 inner diameter of the annular shoulder is typically
10 increased by a multiple of a wall thickness of the
11 tubular member. The inner diameter of the annular
12 shoulder is preferably enlarged by an amount between
13 0.5 and 5 times the wall thickness, and most preferably
14 enlarged by an amount between 0.5 and 2 times the wall
15 thickness. Values outside of these ranges may also be
16 used.

17
18 The tubular member is preferably manufactured from a
19 ductile material. Thus, the tubular member is capable
20 of sustaining plastic deformation.

21
22 The expander device is typically used to expand the
23 diameter of the tubular member, pipeline, conduit or
24 the like.

25
26 The radial expansion of the second annular shoulder is
27 preferably greater than the radial expansion of the
28 first annular shoulder.

29
30 The expander device is preferably used to expand a
31 tubular member, the tubular member including coupling
32 means to facilitate coupling of the tubular member into

1 a string, the coupling means being disposed on an
2 annular shoulder provided at at least one end of the
3 tubular member, the tubular member further including at
4 least one recess wherein a friction and/or sealing
5 material is located within the recess.

6
7 The second annular shoulder is preferably spaced apart
8 from the first annular shoulder by a distance
9 substantially equal to the distance between the annular
10 shoulder and the at least one recess of the tubular
11 member. Preferably, the first annular shoulder of the
12 expander device contacts the at least one recess of the
13 tubular member substantially simultaneously with the
14 second annular shoulder of the expander device entering
15 an annular shoulder of the tubular member. The force
16 required to expand the annular shoulder of the tubular
17 member is significantly less than the force required to
18 expand the nominal inner diameter portions of the
19 tubular member. Thus, as the second annular shoulder
20 of the expander device enters the annular shoulder of
21 the tubular member, the force required to expand the
22 nominal inner diameter portions of the tubular member
23 is not required to expand the annular shoulders of the
24 tubular member and the difference in force facilitates
25 an increase in the force which is required to expand
26 the diameter of the at least one recess.

27
28 The expander device is typically manufactured from
29 steel. Alternatively, the expander device may be
30 manufactured from ceramic, or a combination of steel
31 and ceramic. The expander device is optionally
32 flexible.

1

2 The expander device is optionally provided with at
3 least one seal. The seal typically comprises at least
4 one O-ring.

5

6 The expander device is typically propelled through the
7 tubular member, pipeline, tubular or the like using
8 fluid pressure. Alternatively, the device may be
9 pigged along the tubular member or the like using a
10 conventional pig or tractor. The device may also be
11 propelled using a weight (from the string for example),
12 or may be pulled through the tubular member or the like
13 (using drill pipe, rods, coiled tubing, a wireline or
14 the like).

15

16 According to a fourth aspect of the present invention
17 there is provided a tubular member for a wellbore, the
18 tubular member including a friction and/or sealing
19 material applied to an outer surface of the tubular
20 member, the friction and/or sealing material being
21 disposed on a protected portion so that the friction
22 and/or sealing material is substantially protected
23 whilst the tubular member is being run into the
24 wellbore.

25

26 Typically, the tubular member is a casing, pipeline,
27 conduit or the like. The tubular member may be of any
28 length, including a pup joint.

29

30 The protected portion typically comprises a valley
31 located between two shoulders. The valley is typically
32 of the same inner diameter as the tubular member. The

1 shoulders typically have an inner diameter that is
2 typically increased by a multiple of a wall thickness
3 of the tubular member. The inner diameter of the
4 shoulder is preferably enlarged by an amount between
5 0.5 and 5 times the wall thickness, and most preferably
6 enlarged by an amount between 0.5 and 2 times the wall
7 thickness. Values outside of these ranges may also be
8 used. The shoulders typically comprise annular
9 shoulders. The valley typically comprises an annular
10 valley.

11
12 Alternatively, the protected portion may comprise a
13 cylindrical portion located substantially adjacent a
14 shoulder portion, wherein the outer diameter of the
15 shoulder portion is preferably of a greater diameter
16 than the outer diameter of the cylindrical portion.
17 The shoulder is preferably located so that the
18 cylindrical portion is substantially protected whilst
19 the tubular member is being run into the wellbore.
20 Thus, the friction and/or sealing material is
21 substantially protected by the shoulder whilst the
22 member is being run into the wellbore. The cylindrical
23 portion is typically of the same inner diameter as the
24 tubular member. The shoulder typically has an inner
25 diameter that is typically increased by a multiple of a
26 wall thickness of the tubular member. The inner
27 diameter of the shoulder is preferably enlarged by an
28 amount between 0.5 and 5 times the wall thickness, and
29 most preferably enlarged by an amount between 0.5 and 2
30 times the wall thickness. Values outside of these
31 ranges may also be used.

32

1 The protected portion may alternatively comprise a
2 recess in the outer diameter of the tubular member.
3 The recess may be machined, for example, or may be
4 swaged. The friction and/or sealing material is
5 typically located within said recess. In these
6 embodiments, the outer diameter of the tubular member
7 remains substantially the same over the length of the
8 member, as the friction and/or sealing material is
9 located within the recess.

10

11 Typically, the tubular member includes coupling means
12 to facilitate coupling of the tubular member into a
13 string. Alternatively, the lengths of tubular member
14 may be welded together or coupled in any other
15 conventional manner.

16

17 The coupling means is typically disposed at each end of
18 the tubular member. The coupling means typically
19 comprises a threaded coupling. The coupling means
20 typically comprises a pin on one end of the tubular
21 member, and a box on the other end of the tubular
22 member. Thus, a casing string or the like can be
23 created by threadedly coupling successive lengths of
24 tubular member.

25

26 The tubular member is preferably manufactured from a
27 ductile material. Thus, the tubular member is capable
28 of sustaining plastic deformation.

29

30 Embodiments of the present invention shall now be
31 described, by way of example only, with reference to
32 the accompanying drawings, in which:-

1 Fig. 1 is a cross-portion of a portion of casing
2 in accordance with a first aspect of the present
3 invention;

4 Fig. 2 is an elevation of an expander device in
5 accordance with a second aspect of the present
6 invention;

7 Fig. 3 illustrates the expander device of Fig. 2
8 located in the casing portion of Fig. 1;

9 Fig. 4 is a graph of force F against distance d
10 that exemplifies the change in force required to
11 expand portions of the casing of Figs 1 and 3;

12 Fig. 5 is a cross-portion of a portion of casing
13 in accordance with a fourth aspect of the present
14 invention;

15 Fig. 6a is a front elevation showing a first
16 configuration of a friction and/or sealing
17 material that may be applied to an outer surface
18 of the portions of casing shown in Figs 1 and 5;

19 Fig. 6b is an end elevation of the friction and/or
20 sealing material of Fig. 6a;

21 Fig. 6c is an enlarged view of a portion of the
22 material of Figs 6a and 6b showing a profiled
23 outer surface;

24 Fig. 7a is a front elevation of an alternative
25 configuration of a friction and/or sealing
26 material that can be applied to an outer surface
27 of the casing portions of Figs 1 and 5; and

28 Fig. 7b is an end elevation of the material of
29 fig. 7a.

30

31 It should be noted that Figs 1 to 3 are not drawn to
32 scale, and more particularly, the relative dimensions

1 of the expander device of Figs 2 and 3 are not to scale
2 with the relative dimensions of a casing portion 10 of
3 Figs 1 and 3. It should also be noted that the casing
4 portions 10, 100 described herein may be of any length,
5 including pup joints.

6
7 The term "valley" as used herein is to be understood as
8 being any portion of casing portion having a first
9 diameter that is adjacent one or more portions having a
10 second diameter, the second diameter generally being
11 greater than the first diameter. The term "recess" as
12 used herein is to be understood as being any portion of
13 casing having a reduced diameter that is less than a
14 nominal diameter of the casing.

15
16 Referring to the drawings, Fig. 1 shows a casing
17 portion 10 in accordance with a first aspect of the
18 present invention. Casing portion 10 is preferably
19 manufactured from a ductile material and is thus
20 capable of sustaining plastic deformation.

21
22 Casing portion 10 is provided with coupling means 12
23 located at a first end of the casing portion 10, and
24 coupling means 14 located at a second end of the casing
25 portion 10. The coupling means 12, 14 are typically
26 threaded connections that allow a plurality of casing
27 portions 10 to be coupled together to form a string
28 (not shown). Threaded coupling 12 is typically of the
29 same hand to that of threaded coupling 14 wherein the
30 coupling 14 can be mated with a coupling 12 of a
31 successive casing portion 10. It should be noted that

1 any conventional means for coupling successive lengths
2 of casing portion may be used, for example welding.

3

4 Expandable casing strings are typically constructed
5 from a plurality of threadedly coupled casing portions.
6 However, when the casing is expanded, the threaded
7 couplings are typically deformed and thus generally
8 become less effective, often resulting in loss of
9 connection, particularly if the casings are expanded by
10 more than, say, 20% of their nominal diameter.

11

12 However, in casing portion 10, the coupling means 12,
13 14 are provided on respective annular shoulders 16, 18.
14 The shoulders 16, 18 are typically of a larger inner
15 diameter E than a nominal inner diameter C of the
16 casing portion 10. Diameter E is typically equal to
17 the nominal inner diameter C plus a multiple y times
18 the wall thickness t; that is, $E = C + yt$. The
19 multiple y can be any value and is preferably between
20 0.5 and 5, most preferably between 0.5 and 2, although
21 values outwith these ranges may also be used.

22

23 Thus, when the casing portion 10 is expanded (as will
24 be described), the diameter E of the shoulders 16, 18
25 is required to be expanded by a substantially smaller
26 amount than that of the nominal inner diameter C. It
27 should be noted that the inner diameter E of the
28 annular shoulders 16, 18 may not require to be
29 expanded. For example, the nominal diameter C may be
30 expanded by, say, 25% which in a conventional
31 expandable casing where the threaded couplings are not
32 provided on annular shoulders of increased inner

1 diameter may result in a loss of connection between
2 successive lengths of casing. However, as the threaded
3 couplings 12, 14 are provided on respective annular
4 shoulders 16, 18, then the shoulders are expanded by a
5 smaller amount (if at all), for example around 10%,
6 which significantly reduces the detrimental effect of
7 the expansion on the coupling and substantially reduces
8 the risk of the connection being lost.

9
10 The outer surface of conventional casing portions is
11 sometimes coated with a friction and/or sealing
12 material such as rubber. Thus, when the casing is run
13 into the wellbore and expanded, the friction and/or
14 sealing material contacts the formation surrounding the
15 borehole, thus enhancing the contact between the casing
16 and the formation, and optionally providing a seal in
17 the annulus between the casing and the formation.

18
19 However, as the lengths of casing are being run into
20 the well, the friction and/or sealing material is often
21 abraded during the process, particularly in boreholes
22 that are highly deviated, thus destroying the desired
23 objective.

24
25 Casing portion 10 is also provided with at least one
26 recess 20 that has an axial length A_L , and in which a
27 rubber compound 22 or other friction and/or sealing
28 increasing material may be positioned. The recess 20
29 in this embodiment is an annular recess, although this
30 is not essential. The inner diameter D of the recess
31 20 is typically reduced by some multiple x times the
32 wall thickness t ; that is, $D = C - xt$. The multiple x

1 can have any value, but is preferably between 0.5 and
2 5, most preferably between 0.5 and 2, although values
3 outwith these ranges may also be used.

4
5 The recess 20 is typically weakened using, for example,
6 heat treatment. When expanded, the recess 20 becomes
7 stronger and the heat treatment results in the recess
8 20 being more easily expanded.

9
10 When the recess 20 is expanded, the friction and/or
11 sealing material 20 becomes proud of an outer surface
12 10s of the casing portion 10 and thus contacts the
13 formation surrounding the wellbore. However, as the
14 friction and/or sealing material 22 is substantially
15 within the recess 20 before expansion of the casing
16 portion 10, then the material 22 is substantially
17 protected as the casing portion 10 is being run into
18 the wellbore thus substantially reducing the
19 possibility of the material 20 becoming abraded.

20
21 In this particular embodiment, the friction and/or
22 sealing material 22 is located within the recess 20,
23 and typically comprises any suitable type of rubber or
24 other resilient material. For example, the rubber may
25 be of any suitable hardness (e.g. between 40 and 90
26 durometers or more). In this embodiment, the material
27 22 simply fills the recess 20, but the material 22 may
28 be configured and/or profiled, such as those shown in
29 Figs 6 and 7 described below.

30
31 Thus, there is provided a casing portion that can be
32 radially expanded with reduced risk of loss of

1 connection at the threaded couplings due to the
2 provision of the couplings on annular shoulders.
3 Additionally, the recess prevents the friction and/or
4 sealing material from becoming abraded when the casing
5 is run into a wellbore.

6
7 Referring now to Fig. 2, there is shown an expander
8 device 50 for use when expanding the casing portion 10.
9 The expander device 50 is provided with a first annular
10 shoulder 52 at or near a first end thereof, typically
11 at a leading end 50l. The largest diameter of the
12 first annular shoulder 52 is dimensioned to be
13 approximately the same as, or slightly less than, the
14 nominal diameter C of the casing portion 10.

15
16 Spaced apart from the first annular shoulder 52 is a
17 second annular shoulder 54, typically provided at or
18 near a second end of the expander device 50, for
19 example at a trailing end 50t. The diameter of the
20 second annular shoulder 54 is typically dimensioned to
21 be the final expanded diameter of the casing portion
22 10.

23
24 The expander device 50 is typically manufactured of a
25 ceramic material. Alternatively, the device 50 may be
26 of steel, or a combination of steel and ceramic. The
27 device 50 is optionally flexible so that it can flex
28 when being propelled through a casing string or the
29 like (not shown) whereby it can negotiate any
30 variations in the internal diameter of the casing or
31 the like.

32

1 Referring now to Fig. 3, there is shown the expander
2 device 50 within the casing portion 10 in use. The
3 expander device 50 is propelled along the casing string
4 using, for example, fluid pressure in the direction of
5 arrow 60. The device 50 may also be pigged in the
6 direction of arrow 60 using a pig or tractor for
7 example, or may be pulled in the direction of arrow 60
8 using drill pipe, rods, coiled tubing, a wireline or
9 the like, or may be pushed using fluid pressure, weight
10 from a string or the like.

11
12 As the device 50 is propelled along the casing string,
13 the internal diameter of the string (and thus the
14 external diameter) is radially expanded. The plastic
15 radial deformation of the string causes the outer
16 surface 10s of the casing portion 10 to contact the
17 formation surrounding the borehole (not shown), the
18 formation typically also being radially deformed.
19 Thus, the casing string is expanded wherein the outer
20 surface 10s contacts the formation and the casing
21 string is held in place due to this physical contact
22 without having to use cement to fill an annulus created
23 between the outer surface 10s and the formation. Thus,
24 the increased production cost associated with the
25 cementing process, and the time taken to perform the
26 cementing process, are substantially mitigated.

27
28 The casing portion 10 is typically capable of
29 sustaining a plastic deformation of at least 10% of the
30 nominal inner diameter C. This allows the casing
31 portion 10 to be expanded sufficiently to contact the

1 formation whilst preventing the casing portion 10 from
2 rupturing.

3

4 The force required to expand the diameter of the casing
5 portion 10 by, say, 20% can be considerable. In
6 particular, when the expander device 50 is propelled
7 along the casing portion 10, the first annular shoulder
8 52 is used to expand the annular recess 20 to a
9 diameter substantially equal to that of the nominal
10 diameter C of the casing portion 10. Additionally, the
11 second annular shoulder 54 is required to expand the
12 nominal diameter C of the casing portion 10 whereby the
13 outer surface 10s contacts the surrounding formation.

14

15 It is apparent that the force required to
16 simultaneously expand the recess 20 and the nominal
17 diameter C is considerable. Thus, dimension A (which
18 is the longitudinal distance between the first and
19 second annular shoulders 52, 54) is advantageously
20 designed to be slightly greater than a dimension B.
21 Dimension B is the longitudinal distance between a
22 point 62 where the diameter E of the annular shoulder
23 16 begins to reduce down to the nominal diameter C, and
24 a point 64 where the nominal diameter C begins to
25 reduce down to the diameter D of the annular recess 20.

26

27 The reductions or increments in diameter between
28 diameters C, D and E of casing portion 10 are typically
29 radiused to facilitate the expansion process.

30

31 The distance between the point 62 and the end 66 of the
32 casing portion is defined as dimension F taking into

1 account an overlap that results from the threaded
2 coupling of consecutive casing portions 10. It then
3 follows that dimension A is substantially equal to
4 dimension B plus two times F, taking into account the
5 overlap.

6

7 Referring to Fig. 4, there is shown a graph of force F
8 against distance d that exemplifies the change in force
9 required to expand the diameters C, D and E.

10

11 Force F_N is the nominal force required to expand
12 portions of the casing portion 10 with nominal diameter
13 C. Force F_D is the reduced force that is required to
14 expand the portions of the casing portion 10 with
15 diameter E. Force F_R is the increased force that is
16 required to expand the recess 20 whilst simultaneously
17 expanding portions of the casing 10 with diameter E
18 (that is forces $F_N + F_D$).

19

20 As the expander device 50 is propelled along the casing
21 string the force F_N is generated to expand the casing
22 string. When the expander device 50 reaches a point 68
23 (Fig. 3) where the second annular shoulder 54 of the
24 expander device 50 enters the annular shoulder 16 of
25 the casing portion 10, then the force reduces as the
26 annular shoulder 16 requires to be expanded by a
27 relatively smaller amount. This is shown in Fig. 4 as
28 a gradual decrease in force to F_D , which is the force
29 required to expand the portions of the casing string
30 having diameter E (i.e. the annular shoulders 16, 18).

31

1 As the expander device 50 continues to be propelled in
2 the direction of arrow 60, then the first annular
3 shoulder 52 of the expander device 50 contacts the
4 recess 20 at point 64 (Fig. 3). As can be seen in Fig.
5 4, a total force F_T that would be required to expand the
6 portions of casing 10 having a nominal diameter C and
7 the recess 20 where annular shoulders 16, 18 are not
8 used is substantially greater than both the nominal
9 force F_N and the decreased force F_D . However, with the
10 reduction in force to the decreased force F_D resulting
11 from the position of the annular shoulders 16, 18 on
12 the casing portion 10, and the relative spacing of the
13 first and second annular shoulders 52, 54 on the
14 expander device 50, the force F_R required to expand the
15 recess 20 and the annular shoulders 16, 18 is
16 substantially less than the total force F_T that would
17 have been required to expand a casing without the
18 annular shoulders 16, 18.

19
20 Thus, when dimension A is substantially equal to, or
21 slightly less than, dimension B plus two times F, the
22 first annular shoulder 52 contacts the recess 20 when
23 the second annular shoulder 54 enters the portion of
24 the casing portion 10 with diameter E, thereby allowing
25 the larger force required to expand the recess 20 and
26 the annular shoulders 16, 18 to be made available.

27
28 It should be noted that expansion of the recess 20 is a
29 two-stage process. Firstly, the first annular shoulder
30 52 expands diameter D to be substantially equal to
31 diameter C (i.e. the nominal diameter). Thereafter,
32 the second annular shoulder 54 expands the portions of

1 the casing string having diameter C to be substantially
2 equal to diameter E (or greater if required).

3

4 Referring now to Fig. 5 there is shown a casing portion
5 100 in accordance with a fourth aspect of the present
6 invention. Casing portion 100 is preferably
7 manufactured from a ductile material and is thus
8 capable of sustaining plastic deformation. Casing
9 portion 100 may be any length, including a pup joint.

10

11 Casing portion 100 is provided with coupling means 112
12 located at a first end of the casing portion 100, and
13 coupling means 114 located at a second end of the
14 casing portion 100. Coupling means 112 typically
15 comprises a box connection and coupling means 114
16 typically comprises a pin connection, as is known in
17 the art. The pin and box connections allow a plurality
18 of casings 100 to be coupled together to form a string
19 (not shown). It should be noted that any conventional
20 means for coupling successive lengths of casing portion
21 may be used, for example welding.

22

23 Casing portion 100 includes a friction and/or sealing
24 material 116 applied to an outer surface 100s of the
25 casing portion 100 in a protected portion 118. The
26 protected portion 118 typically comprises a valley 120
27 located between two shoulders 122, 124. It should be
28 noted that casing portion 100 may be provided with only
29 one shoulder 122, 124, where the shoulder 122, 124 is
30 arranged in use to be vertically lower downhole than
31 the friction and/or sealing material 116 so that the
32 material 116 is protected by shoulder 122, 124 whilst

1 the casing portion 100 is being run into the wellbore.
2 In other words, the one shoulder 122, 124 precedes and
3 thus protects the material 116 as the casing portion
4 100 is being run into the hole.

5
6 The shoulders 122, 124 are typically of a larger inner
7 diameter H than a nominal inner diameter G of the
8 casing portion 100. Diameter H is typically equal to
9 the nominal inner diameter G plus a multiple z times
10 the wall thickness t; that is, $H = G + zt$. The
11 multiple z can be any value and is preferably between
12 0.5 and 5, most preferably between 0.5 and 2, although
13 values outwith these ranges may also be used.

14
15 The at least one shoulder(s) 122, 124 are preferably
16 formed by expanding the casing portion 100 with a
17 suitable expander device (not shown) at the surface;
18 i.e. prior to introduction of the casing portion 100
19 into the borehole. The friction and/or sealing
20 material 116 may be applied to the protected portion
21 118 of the outer surface 100s after the shoulders 122,
22 124 have been formed, although the material 116 may be
23 applied to the outer surface 100s prior to the forming
24 of the shoulders 122, 124.

25
26 The protected portion 118 may alternatively comprise a
27 recess (not shown) that is machined in the outer
28 diameter of the casing portion 100. In this
29 embodiment, the friction and/or sealing material 116 is
30 located within the recess so that it is substantially
31 protected whilst the casing portion 100 is run into the
32 wellbore. A further alternative would be to locate the

1 friction and/or sealing material 116 on a swaged
2 portion (i.e. a crushed portion), thus forming a
3 protected portion of the casing portion 100. These
4 particular embodiments do not require any shoulders to
5 be provided on the casing portion 100.

6
7 It should be noted that the protected portion 118 may
8 take any suitable form; that is it may not for example
9 be strictly coaxial with and parallel to the rest of
10 the casing portion 100.

11
12 As shown in Fig. 5, the friction and/or sealing
13 material 116 may comprise two or more bands of the
14 material 116. The material 116 in this example
15 comprises two typically annular bands of rubber, each
16 band being 0.15 inches (approximately 3.81mm) thick, by
17 five inches (approximately 127mm) long. The rubber can
18 be of any particular hardness, for example between 40
19 and 90 durometers, although other rubbers or resilient
20 materials of a different hardness may be used.

21
22 It should be noted however, that the configuration of
23 the friction and/or sealing material 116 may take any
24 suitable form. For example, the material 116 may
25 extend along the length of the valley 118. It should
26 also be noted that the material 116 need not be annular
27 bands; the material 116 may be disposed in any suitable
28 configuration.

29
30 For example, and referring to Figs 6a to 6c, the
31 friction and/or sealing material 116 could comprise two
32 outer bands 150, 152 of a first rubber, each band 150,

1 152 being in the order of 1 inch (approx. 25.4 mm)
2 wide. A third band 154 of a second rubber is located
3 between the two outer bands 150, 152, and is typically
4 around 3 inches (76.2mm) wide. The first rubber of the
5 two outer bands 150, 152 is typically in the order of
6 90 durometers hardness, and the second rubber of the
7 third band 154 is typically of 60 durometers hardness.

8
9 The two outer bands 150, 152 being of a harder rubber
10 provide a relatively high temperature seal and a back-
11 up seal to the relatively softer rubber of the third
12 band 154. The third band 154 typically provides a
13 lower temperature seal.

14
15 An outer face 154s of the third band 154 can be
16 profiled as shown in Fig. 6c. The outer face 154s is
17 ribbed to enhance the grip of the third band 154 on an
18 inner face of a second conduit (e.g. a preinstalled
19 portion of liner, casing or the like, or a wellbore
20 formation) in which the casing portion 100 is located.

21
22 As a further alternative, and referring to Figs 7a and
23 7b, the friction and/or sealing material 116 can be in
24 the form of a zigzag. In this embodiment, the friction
25 and/or sealing material 116 comprises a single
26 (annular) band of rubber that is, for example, of 90
27 durometers hardness and is about 2.5 inches
28 (approximately 28 mm) wide by around 0.12 inches
29 (approximately 3 mm) deep.

30
31 To provide a zigzag pattern and hence increase the
32 strength of the grip and/or seal that the material 116

1 provides in use, a number of slots 160 (e.g. 20) are
2 milled into the band of rubber. The slots 160 are
3 typically in the order of 0.2 inches (approximately 5
4 mm) wide by around 2 inches (approximately 50 mm) long.
5 The slots 160 are milled at around 20 circumferentially
6 spaced-apart locations, with around 18° between each
7 along one edge of the band. The process is then
8 repeated by milling another 20 slots 160 on the other
9 side of the band, the slots on the other side being
10 circumferentially offset by 9° from the slots 160 on
11 the other side.

12

13 It should be noted that the casing portion 100 shown in
14 Fig.5 is commonly referred to as a pup joint that is in
15 the region of 5 - 10 feet in length. However, the
16 length of the casing portion 100 could be in the region
17 of 30 - 45 feet, thus making the casing portion 100 a
18 standard casing pipe length.

19

20 The embodiment of casing portion 100 shown in Fig. 5
21 has several advantages in that it can be expanded by a
22 one-stage expander device (i.e. a device that is
23 provided with one expanding shoulder), typically
24 downhole. Thus, the casing portion 100 can be radially
25 expanded by any conventional expander device.
26 Additionally, casing portion 100 is easier and cheaper
27 to manufacture than casing portion 10 (Figs 1 and 3).

28

29 Casing portion 100 may be used as a metal open hole
30 packer. For example, a first casing portion 100 may be
31 coupled to a string of expandable conduit, and a second
32 casing portion 100 also coupled into the string,

1 ...longitudinally (i.e. axially) spaced from the first
2 casing portion 100. Thus, when the string of
3 expandable conduit is expanded, the space between the
4 first and second casing portions 100 will be isolated
5 due to the friction and/or sealing material.

6
7 Thus, there is provided a casing portion that can be
8 radially expanded with a reduced risk of loss of
9 connection between the casing portions. In addition,
10 the casing portion in certain embodiments is provided
11 with at least one recess wherein a friction and/or
12 sealing material (for example rubber) is housed within
13 the recess whereby the material is substantially
14 protected whilst the casing string is being run into
15 the wellbore. Thereafter, the friction and/or sealing
16 material becomes proud of the outer surface of the
17 casing portion once the casing string has been
18 expanded.

19
20 Additionally, there is provided an expander device that
21 is particularly suited for use with the casing portion
22 according to the first aspect of the present invention.
23 The interspacing between the first and second annular
24 shoulders in certain embodiments of the expander device
25 is chosen to coincide with the interspacing between the
26 annular shoulders and the at least one recess of the
27 casing portion.

28
29 There is additionally provided an alternative casing
30 portion that is provided with a protected portion in
31 which a friction and/or sealing material can be
32 located. The protected portion substantially protects

1 the friction and/or sealing material that is applied to
2 an outer surface of the casing whilst the casing is
3 being run into a borehole or the like.
4
5 Modifications and improvements may be made to the
6 foregoing without departing from the scope of the
7 present invention.

1 **CLAIMS** —

2 1. A tubular member for a wellbore, the tubular
3 member including a friction and/or sealing material
4 applied to an outer surface of the tubular member, the
5 friction and/or sealing material being disposed on a
6 protected portion so that the friction and/or sealing
7 material is substantially protected whilst the tubular
8 member is being run into the wellbore.

9

10 2. A tubular member according to claim 1, wherein the
11 protected portion comprises a valley located between
12 two shoulders.

13

14 3. A tubular member according to claim 2, wherein the
15 valley is of the same inner diameter as the tubular
16 member.

17

18 4. A tubular member according to claim 2 or claim 3,
19 wherein the shoulders have an inner diameter that is
20 increased by a multiple of a wall thickness of the
21 tubular member.

22

23 5. A tubular member according to claim 1, wherein the
24 protected portion comprises a cylindrical portion
25 located substantially adjacent a shoulder portion,
26 wherein an outer diameter of the shoulder portion is of
27 a greater diameter than an outer diameter of the
28 cylindrical portion.

29

30 6. A tubular member according to claim 5, wherein the
31 shoulder is located so that the cylindrical portion is

1 substantially protected whilst the tubular member is
2 being run into the wellbore.

3

4 7. A tubular member according to claim 5 or claim 6,
5 wherein the cylindrical portion is of the same inner
6 diameter as the tubular member.

7

8 8. A tubular member according to any one of claims 5
9 to 7, wherein the shoulder has an inner diameter that
10 is increased by a multiple of a wall thickness of the
11 tubular member.

12

13 9. A tubular member according to claim 1, wherein the
14 protected portion comprises a recess in an outer
15 diameter of the tubular member.

16

17 10. A tubular member according to claim 9, wherein the
18 friction and/or sealing material is located within the
19 recess.

20

21 11. A tubular member according to any preceding claim,
22 wherein the tubular member includes coupling means to
23 facilitate coupling of the tubular member into a
24 string.

25

26 12. A tubular member according to claim 11, wherein
27 the coupling means is disposed at each end of the
28 tubular member.

29

30 13. A tubular member according to claim 11 or claim
31 12, wherein the coupling means comprises a threaded
32 coupling.

1

2 14. A tubular member according to claim 12 or claim
3 13, wherein the coupling means comprises a pin on one
4 end of the tubular member, and a box on the other end
5 of the tubular member.

6

7 15. A tubular member for a wellbore, the tubular
8 member including coupling means to facilitate coupling
9 of the tubular member into a string, the coupling means
10 being disposed on an annular shoulder provided at at
11 least one end of the tubular member, the tubular member
12 further including at least one recess wherein a
13 friction and/or sealing material is located within the
14 recess.

15

16 16. A tubular member according to claim 15, wherein
17 the at least one recess is an annular recess.

18

19 17. A tubular member according to claim 15 or claim
20 16, wherein the at least one recess is weakened to
21 facilitate plastic and/or elastic deformation of the at
22 least one recess.

23

24 18. A tubular member according to any one of claims 15
25 to 17, wherein an internal diameter of the at least one
26 recess is reduced with respect to an internal diameter
27 of the tubular member adjacent the recess.

28

29 19. A tubular member according to claim 18, wherein
30 the internal diameter of the at least one recess is
31 reduced by a multiple of a wall thickness of the
32 tubular member.

1

2 20. A tubular member according to any one of claims 15
3 to 19, wherein the coupling means is disposed on an
4 annular shoulder provided at each end of the tubular
5 member.

6

7 21. A tubular member according to any preceding claim,
8 wherein the coupling means comprises a first screw
9 thread provided on an annular shoulder at a first end
10 of the tubular member, and a second screw thread
11 provided on an annular shoulder at a second end of the
12 tubular member.

13

14 22. A tubular member according to claim 20 or claim
15 21, wherein an inner diameter of the annular shoulder
16 is enlarged with respect to an inner diameter of the
17 tubular member adjacent the annular shoulder.

18

19 23. A tubular member according to claim 22, wherein
20 the inner diameter of the annular shoulder is increased
21 by a multiple of a wall thickness of the tubular
22 member.

23

24 24. A tubular member according to any preceding claim,
25 wherein the tubular member is manufactured from a
26 ductile material.

27

28 25. An expander device comprising a body provided with
29 a first annular shoulder, and a second annular shoulder
30 spaced apart from the first annular shoulder.

31

1 26. An expander device according to claim 25, wherein
2 a radial expansion of the second annular shoulder is
3 greater than a radial expansion of the first annular
4 shoulder.

5

6 27. An expander device according to claim 25 or claim
7 26, wherein the expander device is used to expand a
8 tubular member, the tubular member including coupling
9 means to facilitate coupling of the tubular member into
10 a string, the coupling means being disposed on an
11 annular shoulder provided at at least one end of the
12 tubular member, the tubular member further including at
13 least one recess wherein a friction and/or sealing
14 material is located within the recess.

15

16 28. An expander device according to claim 27, wherein
17 the second annular shoulder is spaced apart from the
18 first annular shoulder by a distance substantially
19 equal to the distance between an annular shoulder of a
20 preceding tubular member and the at least one recess of
21 the tubular member.

22

23 29. An expander device according to claim 27 or claim
24 28, wherein the first annular shoulder of the expander
25 device contacts the at least one recess of the tubular
26 member substantially simultaneously with the second
27 annular shoulder of the expander device entering an
28 annular shoulder of the tubular member.

29

30 30. A method of lining a borehole in an underground
31 formation, the method comprising the steps of lowering
32 a tubular member into the borehole, the tubular member

- 1 including coupling means to facilitate coupling of the
2 tubular member into a string, the coupling means being
3 disposed on an annular shoulder provided at at least
4 one end of the tubular member, the tubular member
5 further including at least one recess wherein a
6 friction/sealant material is located within the recess,
7 and applying a radial force to the tubular member using
8 an expander device to induce a radial deformation of
9 the tubular member and/or the underground formation.
10
- 11 31. A method according to claim 30, wherein the
12 expander device comprises a body provided with a first
13 annular shoulder, and a second annular shoulder spaced
14 apart from the first annular shoulder.
15
- 16 32. A method according to claim 30 or claim 31,
17 wherein the method includes the further step of
18 removing the radial force from the tubular member.

1 / 6

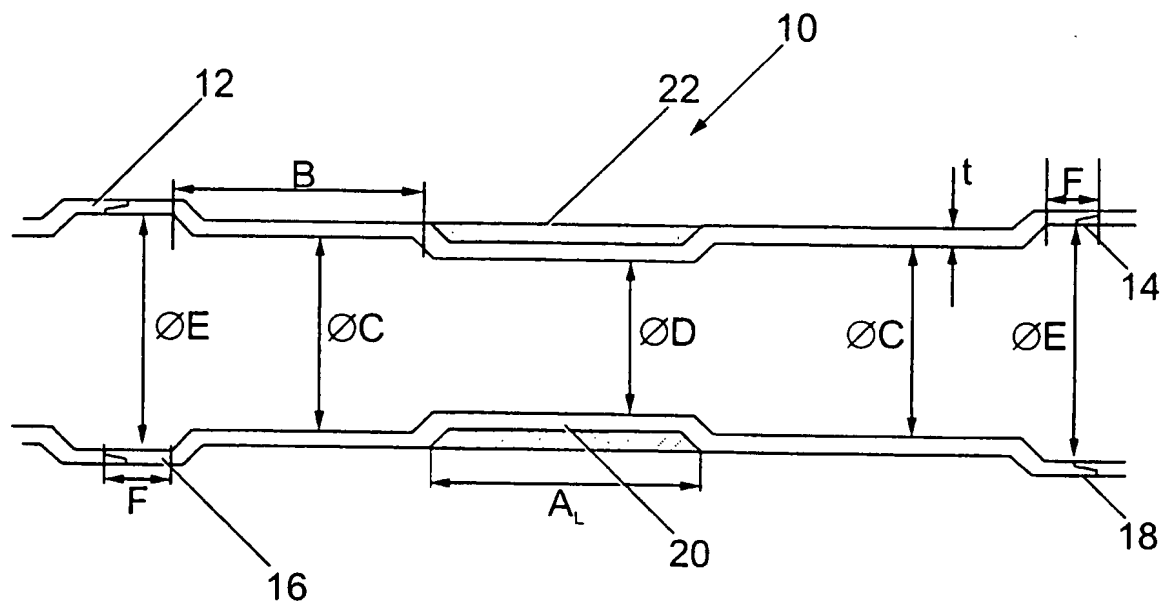


Fig. 1

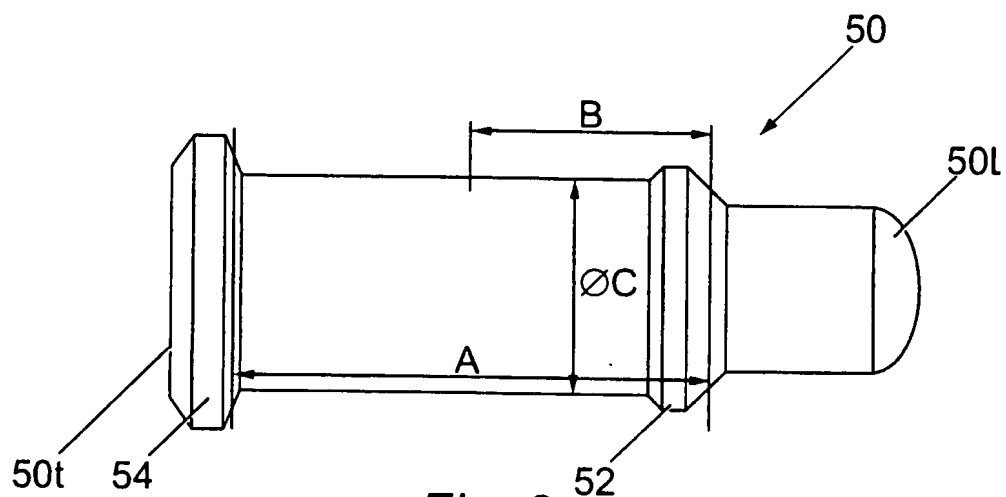


Fig. 2

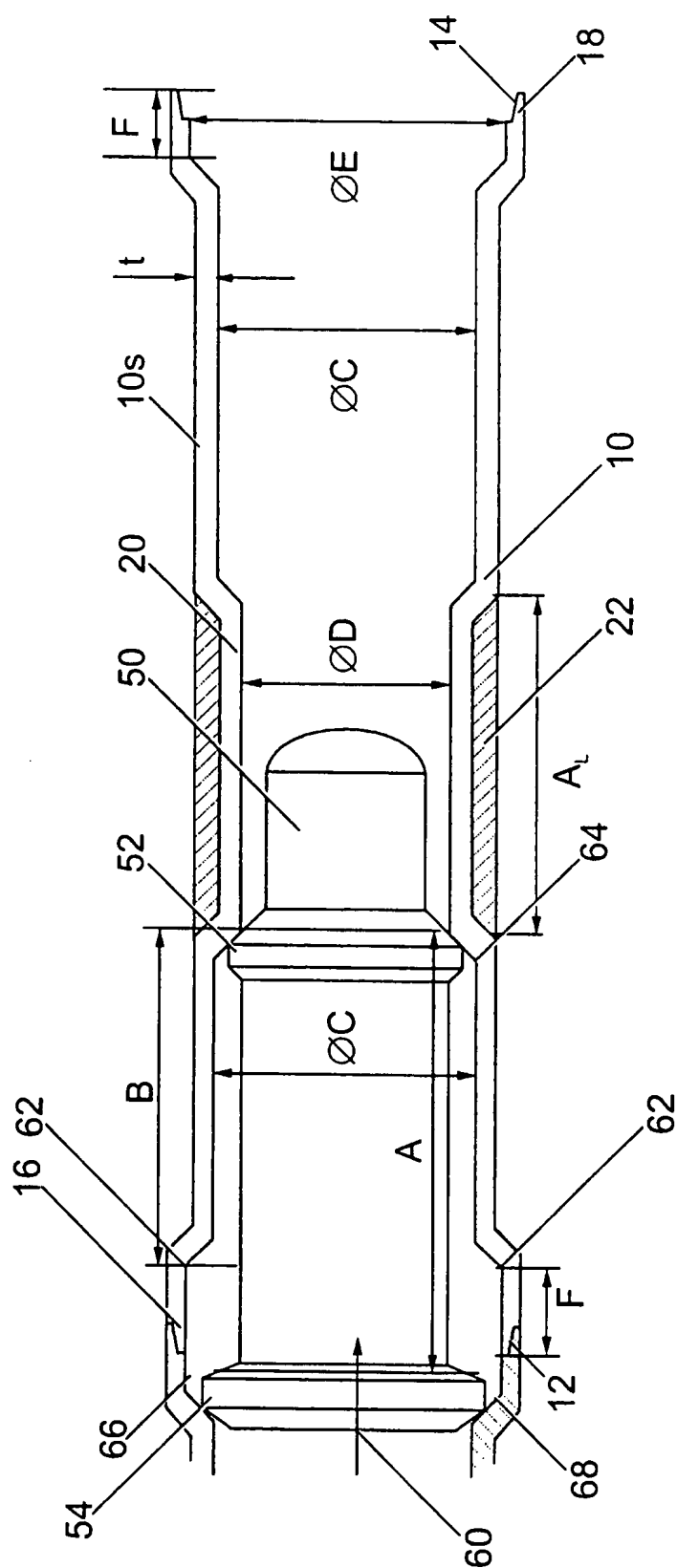


Fig. 3

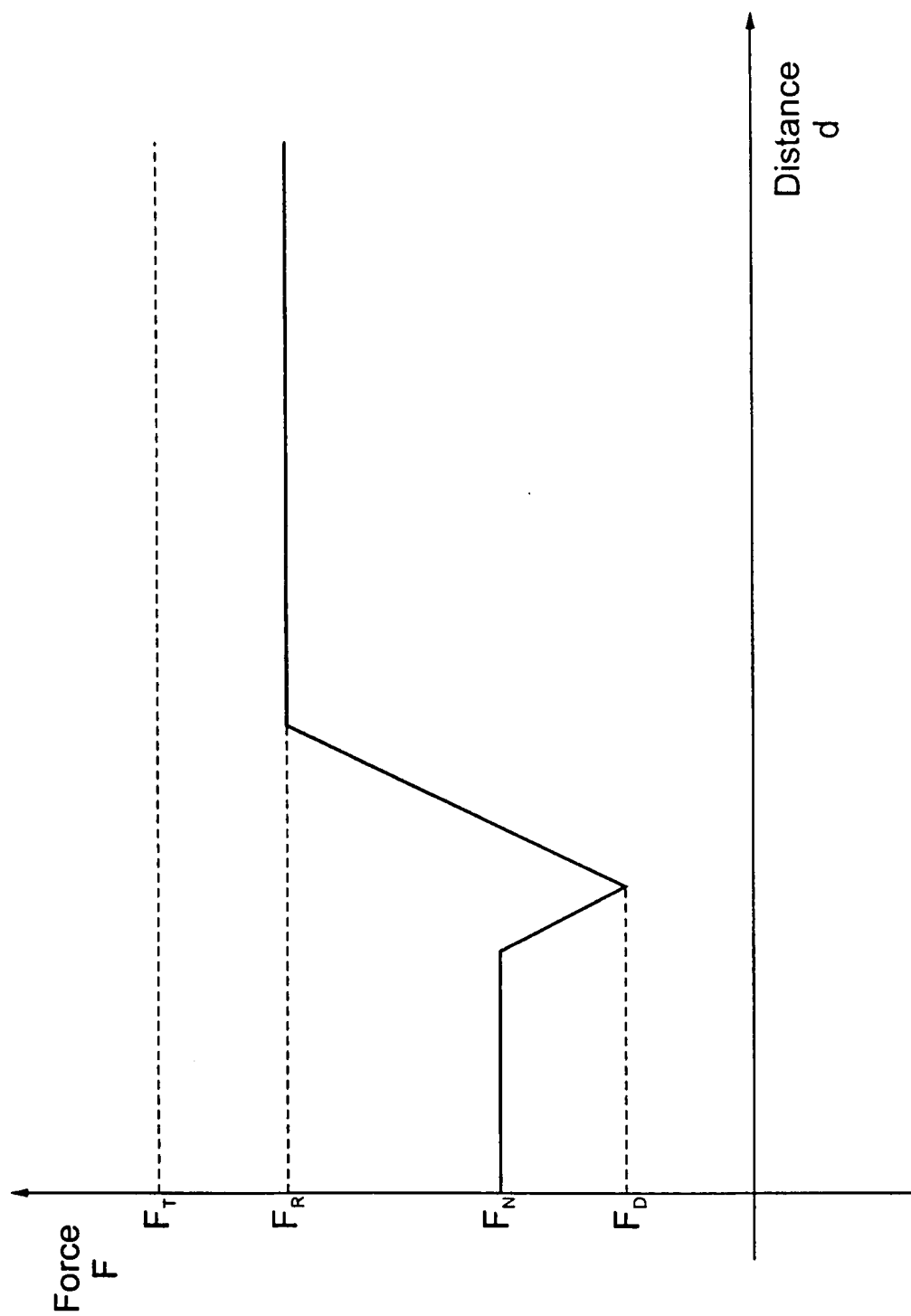
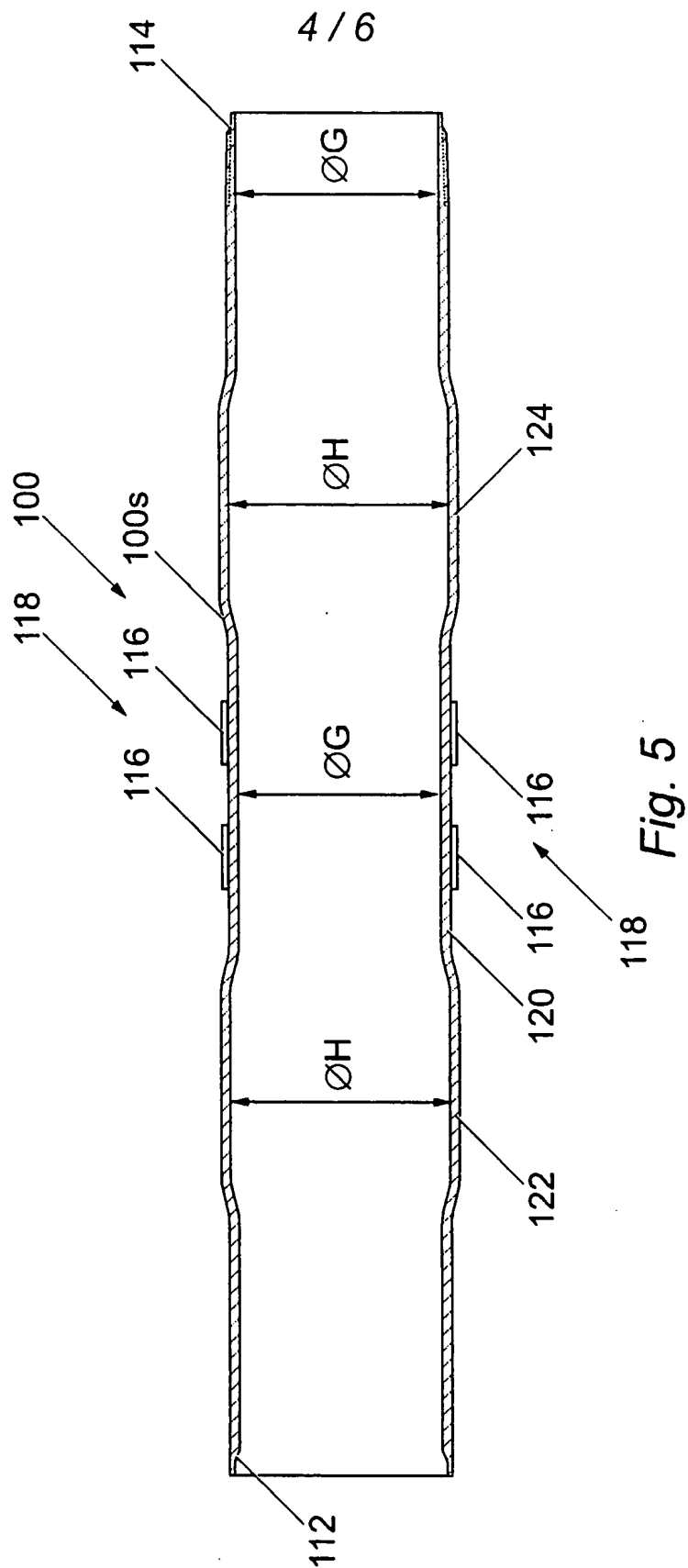
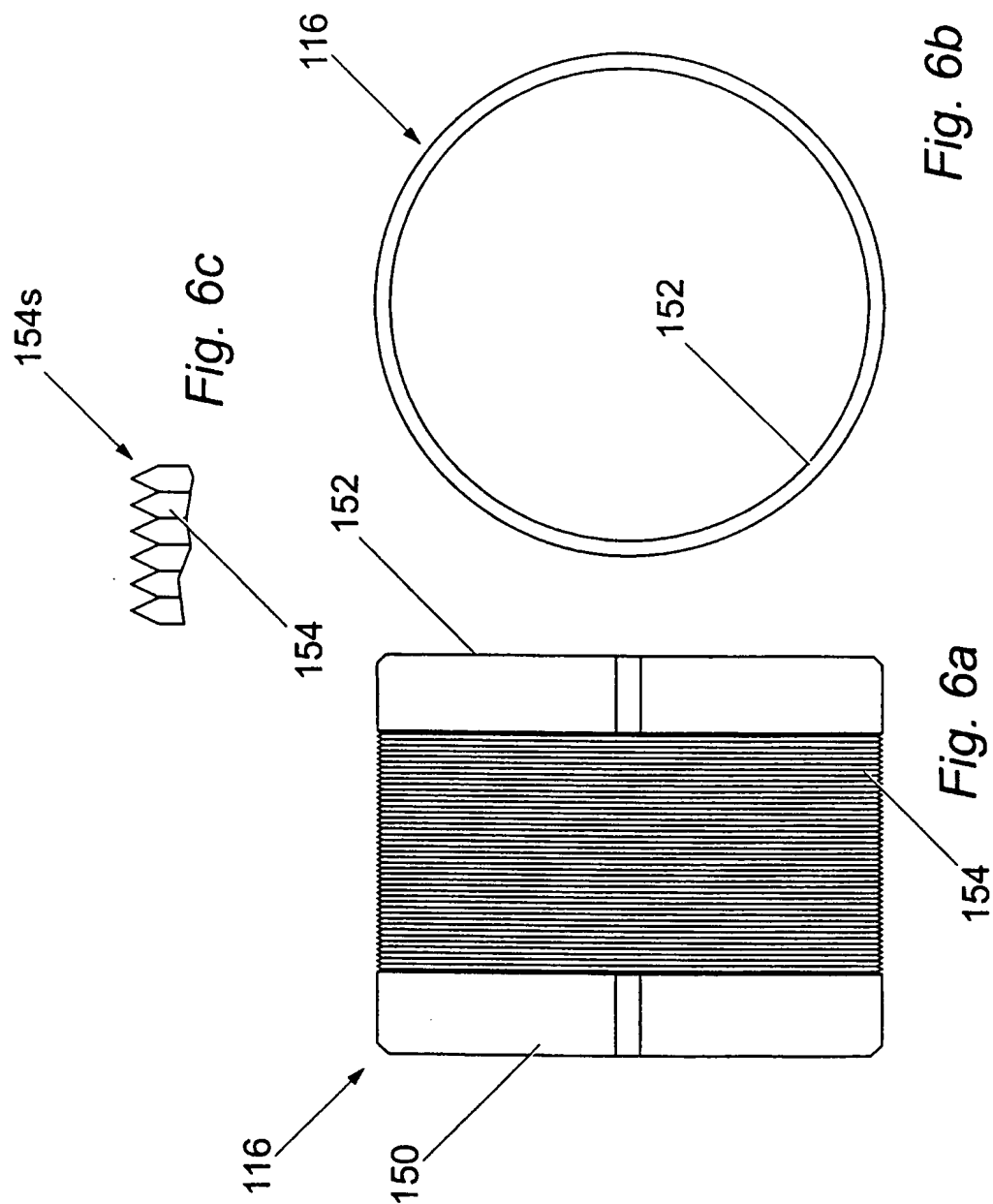


Fig. 4



5 / 6



6 / 6

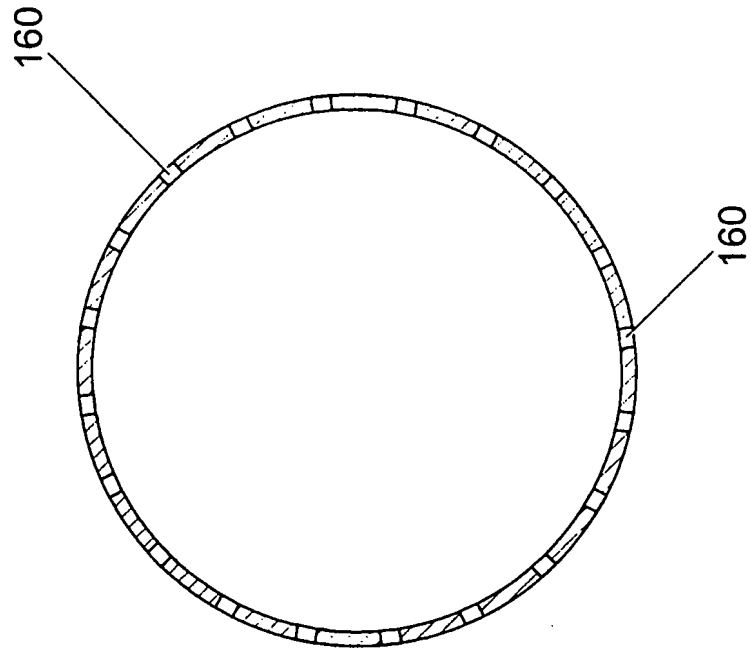


Fig. 7b

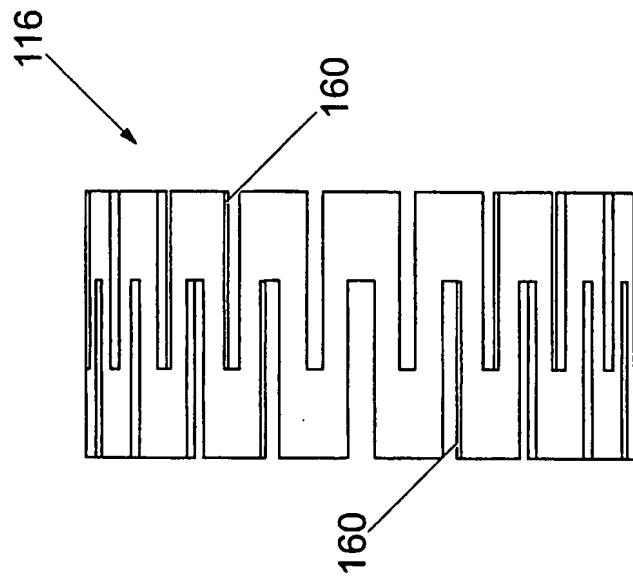


Fig. 7a

INTERNATIONAL SEARCH REPORT

International Application No
PCT/GB 00/03403

A. CLASSIFICATION OF SUBJECT MATTER
IPC 7 E21B43/10 E21B29/10 F16L55/162

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
IPC 7 E21B F16L

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)

EPO-Internal

C. DOCUMENTS CONSIDERED TO BE RELEVANT

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Y	WO 97 21901 A (CAMPBELL ALASDAIR ;METCALFE PAUL DAVID (GB); PETROLINE WIRELINE SE) 19 June 1997 (1997-06-19) page 7, line 17 -page 8, line 11; figure 3	2,15,16, 18-21, 24,30-32
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Y	---	31
	-/--	

☒ Further documents are listed in the continuation of box C.

☒ Patent family members are listed in annex.

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Date of the actual completion of the international search

16 November 2000

Date of mailing of the international search report

24/11/2000

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INTERNATIONAL SEARCH REPORT

International Application No

PCT/GB 00/03403

C.(Continuation) DOCUMENTS CONSIDERED TO BE RELEVANT

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